NORTHEAST POWER MARKETS
ENERGY WATCH

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EXECUTIVE SUMMARY

In this quarterly issue of *Energy Watch*, ESAI assesses the current investment environment in the context of the ongoing recession, possible CO2 legislation, increasing renewables requirements and the tight credit environment. In the regional markets, ESAI looks at forward energy and capacity revenue expectations in order to determine the financial valuation of a combined cycle plant in each of the three Northeast markets.

ESAI examines the diminishing supply role of LNG in the US natural gas markets even in the context of growing global supplies. Estimates of the need for LNG imports in 2030 have dropped from 4.4 Tcf to 0.8 Tcf due to the more optimistic outlook for domestic production, due in large part to unconventional shale gas supplies. Global LNG production is expected to increase from 8,200 Bcf/yr in 2006 to 18,000 Bcf/yr in 2014.

This issue of ESAI's Northeast Energy Watch Quarterly reflects collaboration between ESAI and Charles River Associates (CRA), under which senior CRA analysts have provided targeted contributions, high-value insight and additional input into this ESAI report. This joint effort is designed to deliver additional value to ESAI's Northeast Power Service clients through the breadth of our combined perspectives. Please note ESAI and CRA remain unique organizations dedicated to their respective client bases.

In this Issue

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In our April 2008 issue of *Energy Watch*, ESAI outlined the many market risks in the merchant markets for generation and asked the question – "Who is the rational investor?" At that time, spark spreads were robust due to high natural gas prices and capacity markets provided hope as the outlook for continued strong load growth would lead to a need for new resource additions to meet reserve margins. Since that time, the economic recession has resulted in much lower load growth projections, lower spark spreads, and capacity markets are struggling with surpluses due to both lower peak loads and the stronger presence of PPA supported capacity additions.

In this issue of *Energy Watch*, we provide an overview of the current investment climate in the power sector. We also contrast and compare the investment opportunities in different sectors of the market. While the opportunity to build a purely merchant combined cycle or coal plant is all but dead, there are opportunities for investment in both the renewable energy and transmission sectors. The trend towards PPA supported conventional generation is likely to continue in New York and New England, and is beginning to emerge in PJM, where rate-base supported investment has already been active.

FINANCIAL PENDULUM SWINGS TO CONSERVATIVE

In 2000, the financial pendulum was at the far left; capital was relatively easy to obtain, merchant plants were financed on highly levered terms and due diligence requirements were lax. After the Enron collapse, the pendulum had swung to the far right such that by 2004, merchant plants were very difficult to finance and highly levered terms were no longer available. By 2008, the pendulum had worked its way back towards the middle with some merchant capacity moving forward but on more conservative leverage terms and much of the pricing risk hedged. The pendulum has now pushed again to the far right, as the credit crisis again makes the ability to borrow capital extremely difficult.

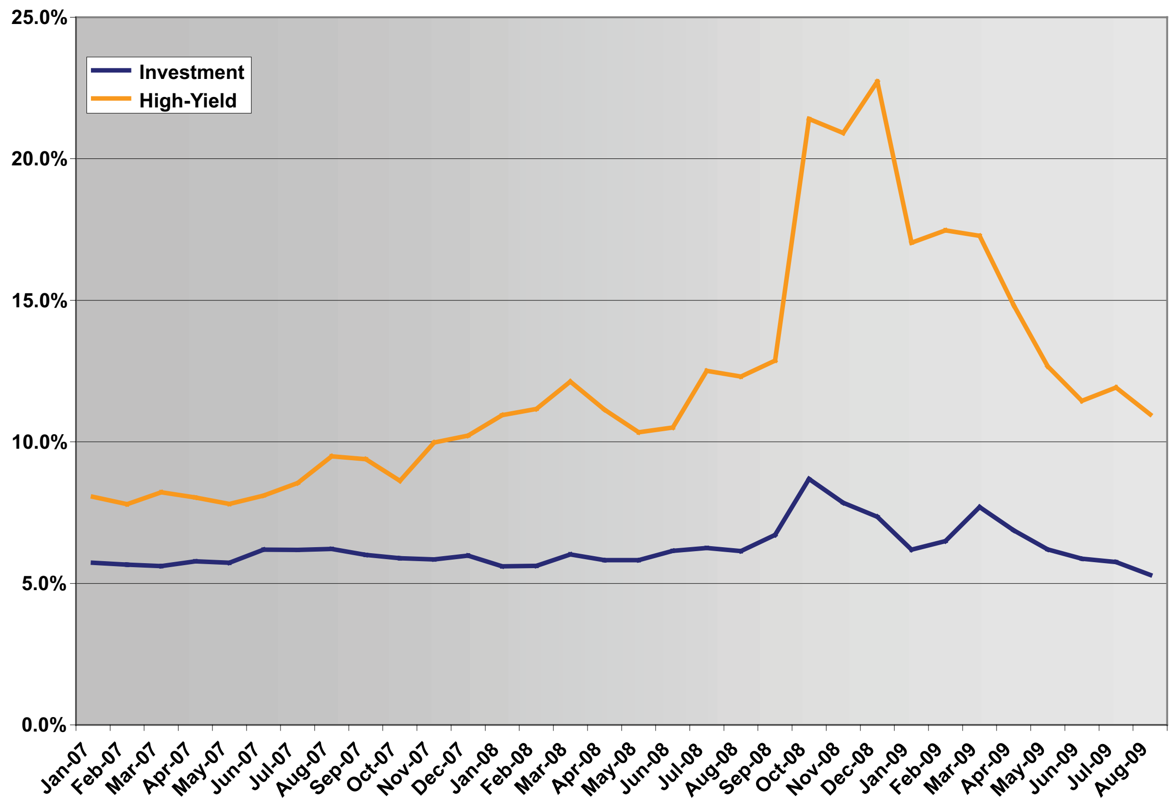
Thus, even merchant developers with an interesting niche or a compelling competitive advantage are finding it difficult to obtain project financing due to the perception that the risks in the merchant energy and capacity markets are too high to warrant the financial support of a new conventional generating facility.

For example, Competitive Power Ventures (CPV) recently filed a petition with the Maryland PUC seeking it to order the state's utilities to enter into a long-term PPA to support construction of its St. Charles Project. CPV asserted that, notwithstanding the fact that there are concerns that Maryland may have insufficient generation in the near future, and that its project is the only new utility-scale generation that could be in operation by 2012, CPV has been unable to secure financing or long-term contracts. CPV summarized the state of the credit market for independents glumly:

"During the last ten years, there have been periods when significant debt amounts, often greater than 50.0 percent of a project's total costs, have been raised for merchant gas-fired power plants that were supported only by short-term contractual commitments, such as energy hedges for 3 to 5 years, or no hedges whatsoever for capacity revenues. But these days are gone. Specifically, traditional commercial banks no longer are willing to finance the types of risks they might once have undertaken; nor will they be willing to rely on third party consultant reports estimating a project's potential revenue stream in a particular wholesale market. Rather, since the collapse of the credit markets, debt markets have required, and, for the reasonably foreseeable future unquestionably will continue to require, a fixed revenue stream of significant duration in order for lenders to finance new baseload or intermediate power plants in wholesale competitive markets such as PJM. In short, such plants simply won't be built absent the relative certainty that long-term contracts with creditworthy utilities can provide to satisfy lenders."[1]

Not only has the availability of credit sharply declined for merchant projects, but the cost of debt has been on a roller-coaster ride during the financial meltdown. As shown in Figure 1, bond yields spiked in late 2008, when high-yield corporate bond yields touched 25.0 percent, and again in spring of 2009, when the yield rose to nearly 20.0 percent. Even yields on investment grade bonds rose well above historically typical levels of 5.50 percent to 6.25 percent to as high as 8.0 percent in 2009. Of particular interest to the shape of power generation development, however, is the spread between investment-grade and high-yield bonds, shown in Figure 2.

Figure 1 - FINRA-Bloomberg U.S. Corporate Bond Indices, Yields



[1] Motion of CPV Maryland, LLC for an Order Requiring Investor-Owned Utilities to Enter into Long-Term Contracts for the Sale of Power from CPV Maryland, LLC's Proposed 640 MW Generating Facility in Charles County, Maryland and Request for Expedited Treatment, Public Service Commission of Maryland, Case 9117 (July 2009), at 22–23.

GENERATION INVESTMENT CLIMATE

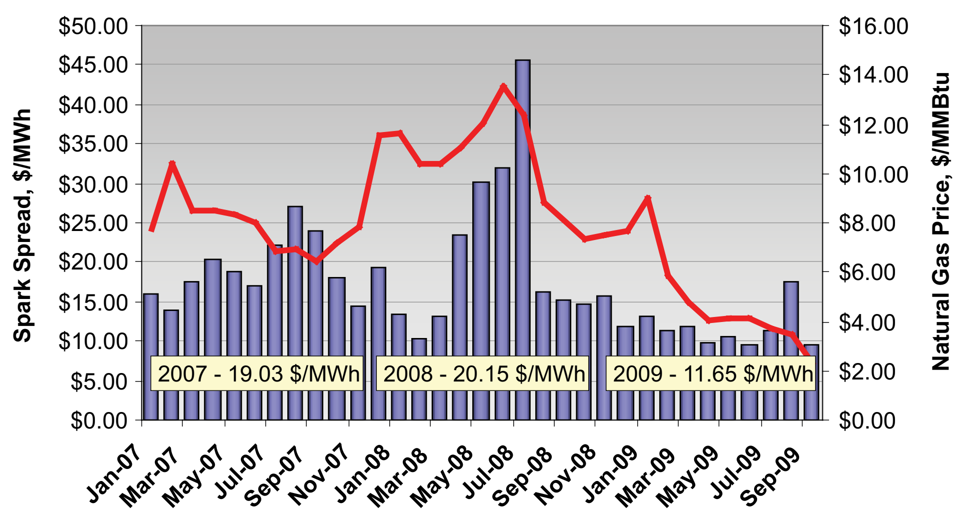
Spark Spreads Laid Low By Gas Prices

Like many other business owners, merchant generation owners are feeling squeezed as the effects of the recessionary environment take hold of the bottom line. The overall drop in demand for most commodities has hit the industry hard, not just in the lower demand for electricity. While overall power demand is a key metric for generators, perhaps more important is the lower demand for natural gas and the attendant drop in spark spreads that comes with lower natural gas prices.

Figure 3 below shows the relationship between Algonquin City Gate natural gas prices and spark spreads at the Mass Hub. In 2007, Mass Hub spark spreads averaged just over $19.00/MWh while 2008 averaged slightly higher at $20.15/MWh. The collapse in natural gas prices from above $13.00/MMBtu to $3.00 has caused a 40 percent drop in spark spreads. The 2009 YTD spark spread averaged only $11.65/MWh with perhaps the weakest season of 2009 still to come.

Gas prices are expected to recover from currently depressed levels to a range of $6.00 to $8.00/MMBtu starting in 2011. The higher gas price environment will be positive for spark spreads, which should recover from the current lows.

Figure 3 - Mass Hub Spark Spread vs. Natural Gas (ACG)



Capacity Prices Mixed

Capacity prices in the Northeast have been pushed lower in most of the markets, although not all of the impact is due to the recession. The one factor that is directly related to the recession, however, is the peak load forecast. Lower peak energy demand forecasts due to the recessionary environment result directly in lower requirements for installed capacity (peak load plus reserve margin). The lower peak demand forecasts result in lower capacity prices in the New York and PJM markets and serve to delay the needs for new capacity.

Other factors impacting capacity markets include new build capacity coming to fruition that commenced construction prior to the recession such as the Kleen Energy plant in Connecticut and the Besicorp-Empire plant in New York. Both of these plants are 620 MW combined cycle facilities that will have significant impacts on their regional capacity markets.

In PJM, RTO prices have been impacted very negatively due to a rule change that makes it easier for an LDA to clear as a constrained area (The CETO/CETL cutoff limit was raised from a ratio of 1.05 to 1.15). The positive side of this rule change is that many LDAs cleared at higher prices than expected including most of eastern PJM and MAAC (MAAC prices cleared just above $4.00/kw-mo; DPL South was the highest clearing LDA at $6.75/kw-mo).

Overall, capacity price outlooks in New England are very weak with capacity clearing prices expected at $4.00/kw-mo or below through 2020, primarily the result of market design issues as well as lower peak load growth outlooks. New York Rest of State capacity is expected to clear below $4.00/kw-mo from 2011 to 2014 before moving higher in 2015 and beyond. PJM RTO capacity prices are expected to clear below $4.00/kw-mo through 2017. Higher capacity prices in eastern PJM and in New York City are notable exceptions to the lower regional prices, but prices in these regions are still well below the required cost of new entry payments for new generators.

Incremental Renewable Demand

Another factor complicating the landscape for conventional generation developers is the amount of new renewable energy capacity that is entering the markets each year. Most states with renewable energy portfolio standards provide for annual increases in the percent requirement of the total load that must be supplied from renewable resources. The typical increase is 1.0 or 1.5 percent per year with most states having a mandate to reach 15 or 20 percent renewable energy supply by 2020.

The increase in the annual renewable energy mandate is in the range of load growth expectations for most regions (1.5 percent being optimistic under most current outlooks). In other words, load growth is being met – or exceeded – by new renewable generation and the need for new incremental conventional generation is extremely limited.

Likewise, the state of Connecticut has issued RFPs for over 1,300 MW of peaking and combined cycle capacity and awarded lucrative PPAs to the winners. This capacity has likewise added to the surplus capacity currently flooding the New England market.

It is possible that the contracted asset model (as supported by LSE issued PPAs) will be self-fulfilling. Merchant margins have been depressed in New York and New England due in large part to the entry of contracted assets who achieve a fully profitable cost recovery for little or no risk. The threat of contracted asset entry is likely to deter developers from moving projects toward financing and construction. Developers are then likely to work on projects that could eventually win a PPA with a local utility. This “If you can’t beat ‘em, join ‘em” attitude will not only stem from the developer’s desire to reduce risk, but also from financing entities who increasingly are only willing to back projects with PPAs covering the majority of their capacity.

For their part, LSEs are unwilling to hold out to see if a merchant developer will come in at the 11th hour to build a plant that is needed to maintain reserve margins. The LSE will project reserve margin shortfalls and contract for a new asset to be built well ahead of when a merchant developer might commit. In this manner, the LSE blocks out the merchant player and the early addition of the plant keeps energy and capacity prices below the requirements for new entrants.

RENEWABLE INVESTMENT CLIMATE

While merchant investments in conventional fossil-fuel generation, especially coal, face significant hurdles, there are a few reasons why the investment climate for renewable generation is expected to be remain more attractive. Most prominently, renewable projects benefit from incentives through the investment tax credit and production tax credit. These programs, which have been solidified by the provisions in the ARRA (noted earlier), are critical for the economics of renewable projects and make them somewhat less dependent on energy pricing. Additional, as renewable portfolio standards (RPS) in many states are beginning to ramp up, liquidity in the REC markets has improved. The magnitude and importance of REC payments and tax credits is demonstrated by the willingness of wind generators to supply energy, rather than curtail production, even at negative prices, often as low as -$50/MWh to -$100/MWh.

The PTC and ITC not only supplement the revenues for wind projects, but also provide a financing vehicle in the form of tax equity, in which developers with limited tax exposure can pass on the tax benefits to financiers with greater taxable earnings to offset. Despite these incentives for renewable energy, the renewable sector has not been without challenges for obtaining financing. Uncertainty regarding the future of subsidies, along with lower energy prices and tight credit markets, have had negative impacts on the renewable sector not unlike the broader merchant sector. However, unlike fossil-fueled generation which faces over-supplied markets and competition from out-of-market capacity, renewable energy developers benefit from growing REC requirements and a limited supply potential, particularly in the near and medium term. Hence, the market prospects for successful renewable projects are much more promising than those for conventional generation.

Meeting the RPS in many states will require expansion of the renewable fleet many times over by the middle to end of the next decade. Additionally, a federal RPS, as proposed in the Waxman-Markey bill, would solidify existing demand from state programs and expand requirements to the remaining states. While equipment supply may be adequate to meet these demands, good sites for projects and transmission capacity to deliver energy from desirable remote locations are significantly more limited. These constraints on supply make it questionable whether some state RPS targets can be met, making pricing at or near the caps established for the various state RPS programs likely for several years. While major transmission projects to allow robust delivery of renewable power to load centers are being proposed, the high cost and difficult siting issues for new transmission means that these projects will face challenges and require significant time to be completed.

These constraints to the addition of renewable energy projects also introduce risks, however. If RPS targets cannot be met, REC prices will remain at high, capped levels and political pressure may make it difficult to maintain these expensive programs that deliver fewer benefits than promised. And, although the ARRA has reduced the uncertainty associated with the ITC and PTC, these subsidy programs may not be sustainable in the longer term under a federal carbon policy. An aggressive carbon policy would lead to higher energy prices that could in turn make renewable energy projects economic without the tax credit subsidies. The greater danger for renewable developers is that high levels of renewable generation will displace the need for significant volumes of conventional energy generation, resulting in lower natural gas demand and lower natural gas prices. Low natural gas prices as seen in the current environment, result in a lower power price regime that makes it more difficult for renewable developers to achieve their desired returns.

A more bullish outlook for renewable generation only makes the outlook for conventional generation more bearish, however. Resource adequacy needs in overbuilt markets now facing reduced demand growth will only be delayed further by addition of renewable generating capacity. While the diurnal and seasonal patterns of generation for renewable projects, especially wind, generally limit their qualified capacity in capacity markets to a fraction of nameplate ratings, the projects will still provide additional capacity and delay the need for new gas and coal generation. The renewable generation also puts downward pressure on electricity prices, especially off-peak. On the more positive side, however, the intermittent nature of wind and solar generation will create the need for additional operating reserves and frequency regulation, creating opportunities for flexible conventional generators.

TRANSMISSION INVESTMENT CLIMATE

In contrast to the climate for generation investment, the past five years have seen a virtual explosion in transmission investment in the Northeast. Transmission investment in New England and PJM has been booming. For its part, the NYISO has also seen a marked increase in transmission investment, albeit of a different nature than in ISO-NE or PJM.

Since 2000, PJM has added almost $3 billion in new transmission investment. Figures from the latest Regional Transmission Expansion Plan (RTEP) indicate a substantial acceleration in investment in several 500 kV and 765 kV backbone projects, with another $5 billion in transmission investment expected to be added by 2014.

New England is also in the midst of a transmission investment boom. From 2002 through 2008, a total of $3.5 billion in transmission investment has been added to the New England system. Projects entering service during this period included significant upgrades to the Boston and Southwest Connecticut load pockets. ISO-NE's Regional System Plan (RSP) includes another $5.1 billion of projects under construction, planned or proposed for the region through 2013. The total amount of in service and planned transmission investment from 2002 through 2013 is a staggering $8.6 billion.

These billions of dollars in investment are driven by robust RTO-administered reliability planning processes and the resolution (for the most part) of cost allocation issues. This level of investment also reflects the abilities of both RTOs (ISO-NE, PJM) to control investment in their respective regions; in other words, the RTOs have clear FERC-approved rules and protocols that provide them with considerable discretion in controlling investment in transmission solutions for reliability problems. RTO planners track resource adequacy and make projections of future needs, but it is important to note that, for the most part, the RTOs are not empowered to build new generation or to financially support the building of new generation. In the event that developers fall short of building capacity that meets the resource needs of the pool, the RTO generally has no authority to order the construction of new generation capacity.[3]

However, the RTOs do have the authority (under FERC jurisdiction) to order transmission solutions to reliability problems and to include the costs of such transmission solutions in regional grid access rates. This authority to push forward a transmission solution to a reliability concern provides a transmission wild card to RTOs for use in maintaining system reliability in the absence of development of new generation or demand resources.

This planning and cost recovery protocol provides attractive opportunities for financing and investment. Moreover, FERC has granted significant financial incentives for much of this investment, such as premium rates of return on equity (as high as 14.0 percent), use of hypothetical capital structures (allowing financing at higher levels of leverage but assuming lower debt/equity ratios for calculating rates for cost recovery), accelerated depreciation schedules, and pre-approved recovery of costs in the event of project cancellation or abandonment.

[3] An exception is ISO-NE, which has the authority to issue solicitations for new capacity (so-called "Gap RFPs") in situations of extreme resource adequacy deficiencies (such as in Southwest Connecticut).

In this section of *Energy Watch,* ESAI provides an overview of three areas of interest in the PJM market arena.

1. Overview of power flow impacts due to First Energy entry to PJM,
2. Long Term Heat Rate Outlook, and
3. Financial Benchmark – CCGT valuation at PJM Western Hub

FIRSTENERGY TRANSITION

On July 31, 2009 FirstEnergy Corporation announced that its Ohio and Penn Power operating companies intend to join PJM and withdraw from the Midwest ISO. Under the plan, effective June 1, 2011, the control of FirstEnergy's transmission facilities owned and operated by its subsidiary American Transmission Systems, Incorporated (ATSI) will be transferred to PJM. This move will effectively trigger the need for generation and loads connected to the ATSI system to realign their operation from Midwest ISO to PJM. As a result, the three Ohio utilities - Ohio Edison, Cleveland Electric Illuminating and Toledo Edison - and Penn Power would join PJM on the same date. FirstEnergy's other operating units, Pennsylvania Electric Co., Metropolitan Edison Co. and Jersey Central Power & Light Co., are already PJM members.

The migration of FirstEnergy to PJM in June 2011 will have numerous implications for the markets:

- The operations of the day-ahead and real-time markets both in the Midwest ISO and PJM will be impacted,
- Changes are anticipated with respect to the outcome of the Reliability Pricing Model (RPM) auctions in PJM, and,
- Markets for FTRs administered by both RTOs will be impacted.

As stated in the FirstEnergy's application with FERC, ATSI has only three interconnections with the rest of the Midwest ISO system and thirty two interconnections with PJM. The transfer capability between ATSI and its neighbors also indicates that it has stronger interties with PJM than with the Midwest ISO (MISO). As shown in Table 1, even with a potential migration of Duquesne to MISO, the balance of flows will remain strongly in favor of PJM. According to FirstEnergy, moving ATSI into PJM will reduce "long and irregular seams" between the two RTOs and should reduce congestion and reduce generation costs in both markets[1].

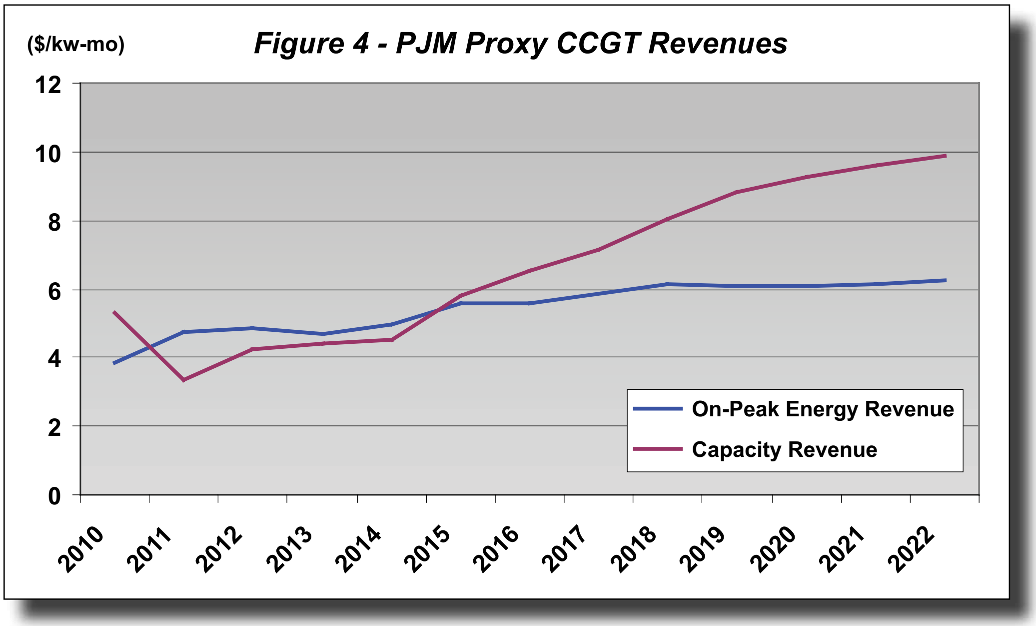
Table 1 - ATSI Interconnections with Midwest ISO and PJM, MW

with Midwest ISO		with PJM	
ITC	4,560	AEP	13,083
		Duquesne	7,029
		Penelec	1,559
		Allegheny	1,490
		DP&L	673

[1] FirstEnergy's application to FERC, Docket ER09-1589-000, August 17, 2009.

FINANCIAL BENCHMARK – PJM WESTERN HUB PLANT VALUATION

As noted in our front piece, merchant generators face significant challenges due to declining spark spreads and lackluster capacity values. While commodity prices have tanked since the start of the recession, new build costs for power plants have not seen commensurate declines and in fact, new build costs have been relatively steady. Current new build costs for combined cycle power plants in PJM are in line with other Northeast locations for non-urban sites and are currently near $1,100/kw, down marginally from the peak levels of 1,200/kw.



Market heat rates have improved substantially in PJM over the past five years. However, despite the increase in market heat rates, the low natural gas pricing environment has caused a dramatic drop in spark spreads – the real determinant for plant profitability. Our long term outlook for spark spreads has decreased since the peak in 2008; energy revenues for a generic combined cycle facility at the PJM Western Hub are down 25 percent. Near term gas prices are much lower than previous projections, but long term gas price projections are only marginally lower, moderating the drop in energy revenue expectations.

Given the recent very low RPM capacity auction results for the 2012/13 RTO auction ($16.50/MW-day), forward capacity projections are much lower than previously anticipated. Due to the change in the CETO/CETL limits for defining LDAs, the eastern LDAs and MAAC will see reasonable capacity price levels, but RTO prices will be depressed. MAAC represents about one half of the RTO capacity, therefore the amount of capacity that will receive RTO or "rest of RTO" prices will be about 70,000 MW. ESAI's 10 year outlook for RTO capacity prices has dropped from $235/MW-day one year ago to just below $100/MW-day due to the LDA definition rule change. Over a longer period, ESAI anticipates that capacity prices will trend towards net CONE, but remain at a discount to net CONE.

In this section of *Energy Watch*, ESAI assesses the long term heat rate outlook for New York at the New York Reference Bus and examines the key factors that support the long term outlook. In addition, ESAI benchmarks the financial outlook for a new combined cycle plant in Zone J, (New York City). This proxy plant would receive Zone J energy and capacity revenues. ESAI's analysis indicates that the net present value of the Zone J combined cycle plant is only $1,100/kw based on EBITDA cash flows[1]. This figure falls far short of the estimated $2,100/kw required to build a new combined cycle plant in New York City largely due to mitigation rules that would exclude new capacity from receiving capacity payments until at least 2020.

LONG TERM HEAT RATE ANALYSIS

Generator Outlook

The transparency of capacity markets based on demand curves allows ESAI to predict the entry of new capacity in both New York City and the Rest of State beyond current projects that are closely monitored by ESAI. As shown in Table 1, ESAI utilizes an expected new generation mix that is reflective of the capacity that will be developed consistent with renewable energy targets and energy efficiency initiatives.

Table 1 - ESAI Expected Capacity Additions, NYISO

New Base Case	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*Total*
Wind, Nameplate	830	440	250	150	200	200	200	200	200	200	200	200	200	3,470
DR Base	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Nuclear	–	–	–	–	–	–	–	–	–	–	–	–	–	–
DR Pkr	1,700	370	150	100	50	50	50	–	–	–	–	–	–	–
Pkr	–	–	–	–	–	100	–	–	–	–	–	–	–	400
CC	–	325	635	545	–	–	–	–	–	–	–	–	500	2,960
Coal, VFT/DC ties	–	300	–	–	600	–	–	–	–	–	–	–	–	900

As seen in Table 1, there is approximately 2,500 MW of new capacity slated for New York (mostly in Zone J) between 2009 and 2013 before considering wind or demand resource additions. Expected retirements total almost 1,000 MW including the Zone J Poletti plant in January 2010 and 100 MW of NRG peakers in 2013 (also in Zone J).

New additions include the 300 MW Linden VFT and the 600 MW Hudson DC line bringing energy and capacity into Zone J from New Jersey (modeled as coal to reflect the base load economics of these projects). The Linden VFT is expected to achieve full commercial on-line status in December 2009. The Hudson project is now slated for 2012, but has not been formally approved by the NYPA board to move forward towards construction.

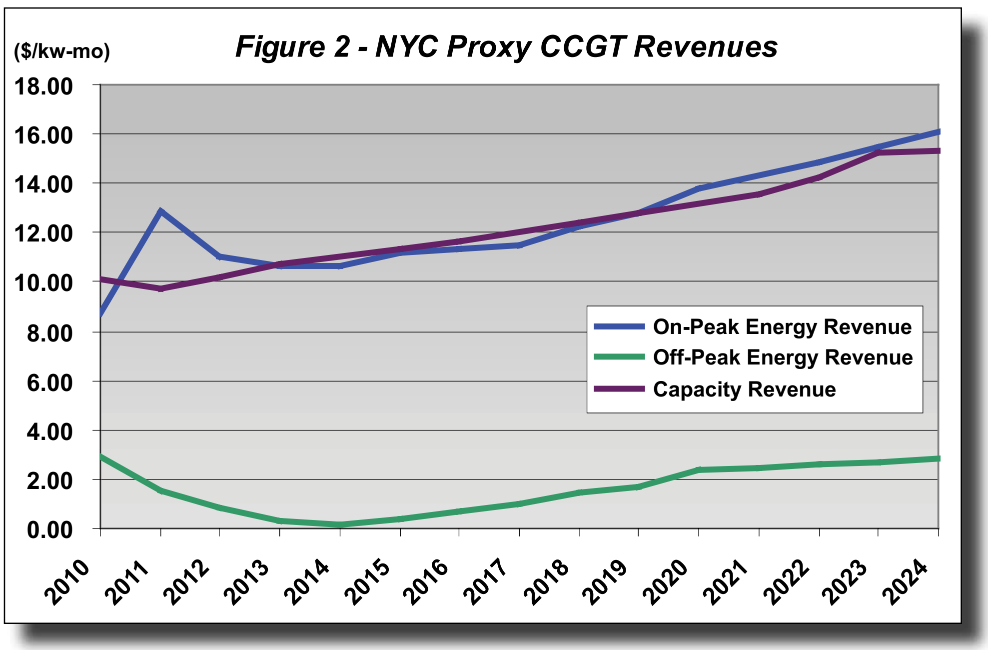
The 325 MW Caithness combined cycle plant on Long Island achieved commercial startup in July 2009 and is partially under contract to LIPA. The 550 MW Besicorp combined cycle addition in Zone F is expected to be completed by September 2010

[1] 20 year cash flows, 12 percent discount rate

FINANCIAL BENCHMARK – ZONE J PLANT VALUATION

The heat rate outlook and energy margins in Zone J remain robust although long term spark spreads are marginally lower than previous forecasts. The big wild card for merchant plants is whether they can collect a capacity payment due to the mitigated price floor in the Zone J capacity market. If a new unit pushes the capacity price below 75 percent of net CONE, then it is mitigated and will receive no capacity payment. Because there is already a surplus of capacity coming into the market, no new capacity is needed in New York City until 2020 or later, meaning that a new merchant plant built in Zone J would not receive capacity payments until 2021.

Figure 2 shows the revenue expectations from capacity and energy for an existing merchant plant. As noted above, a new plant would have zero capacity revenues until 2021. Figure 3 shows the relative contributions from on and off-peak energy and capacity payments against a $25/kw-mo estimate of new build revenue requirements. New build economics in New York City might look attractive if were not for mitigating the ability for a new plant to collect capacity payments. (We note that if the floor was not in place, capacity prices would certainly be lower than the forecast with the floor.)



In the New England section of *Energy Watch*, ESAI assesses the long term energy outlook through implied market heat rates as determined at the Mass Hub. With ESAI's energy forecast and outlook for capacity prices under the Forward Capacity Market (FCM) construct, ESAI benchmarks the financial outlook for a new combined cycle at the Mass Hub. ESAI's analysis indicates that the net present value of a generic state of the art combined cycle plant is just short of $500/kw based on EBITDA cash flows[1]. This figure falls far short of the estimated $1,100/kw required to build a new combined cycle plant in New England. The large gap between estimated earnings and required revenues to meet new build cash flows is largely explained by the poor outlook for FCM capacity revenues and the drop in spark spreads caused mainly by the low natural gas price environment.

LONG TERM HEAT RATE ANALYSIS

Generator Outlook

Since 2007, New England generators have been receiving capacity payments as part of the FCM transition period. Starting in June 2010, generators will begin receiving payments consistent with the results of the February 2008 auction. The 2010 FCM auction cleared at the $4.50 floor with a surplus of 2,047 MW, resulting in an equivalent pro-rated price of $4.25/kw-mo. The 2011 auction similarly cleared at the floor of $3.60 with a total surplus of 4,755 MW, resulting in a pro-rated price of only $3.12/kw-mo.

The surplus in the first two auctions, combined with additional projects in the queue that have qualified for the third auction, yield an active field of new entrants to the New England generation portfolio. Table 1 provides an overview of the expected capacity additions by type and year of entry.

Table 1 - ESAI Expected Capacity Additions, ISO-NE

New Base Case	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*Total*
Wind, Nameplate	–	–	100	145	150	200	350	350	350	500	500	400	300	3,345
DR Base	–	–	200	–	40	–	–	–	–	50	50	50	–	390
Nuclear	–	–	80	–	–	–	–	–	–	–	–	–	–	80
DR Pkr	–	–	1,600	480	160	0	0	80	80	80	80	80	80	2,720
DR DA Bidders	–	–	400	120	40	0	0	20	20	20	20	20	20	680
Pkr	–	–	310	504	–	–	150	200	–	150	150	150	–	1,614
CC	–	–	–	562	–	–	–	–	–	–	–	–	400	962
Coal	–	–	–	–	–	–	–	–	–	–	–	–	–	–

While there was a significant amount of conventional generation that cleared in the first two FCM auctions, new demand resource additions were dominant, bringing the total demand resource capability in New England up to almost 2,800 MW. Conventional generation additions were mostly the result of the Connecticut RFPs for capacity that supported the entry of the 620 MW Kleen Energy facility and approximately 700 MW of peaking capacity. Wind resources are added in accordance with ESAI's study of the queues as well as the need for new resources to meet New England renewable portfolio standards.

[1] 20 year cash flows, 12 percent discount rate.

FINANCIAL BENCHMARK – MASS HUB PLANT VALUATION

Over the past 18 months, the outlook for the New England FCM capacity market has changed significantly for the worse. Capacity prices are on a downward trend that will last until 2020 unless load growth prospects improve or there is a significant retirement of existing capacity. Spark spreads have narrowed in the low gas price environment although heat rates remain relatively stable. The poorer outlook for energy and capacity translates into lower revenue expectations for merchant plants even though new build costs for power plants have remained steady, or at best, declined slightly from the peak levels seen in early 2008. In New England, new CCGT costs were estimated at close to $1,200/kw during 2007 and 2008. Since that time, commodity prices have declined precipitously but new build costs for a combined cycle in New England remain steady at near $1,200/kw or at best, $1,100/kw.

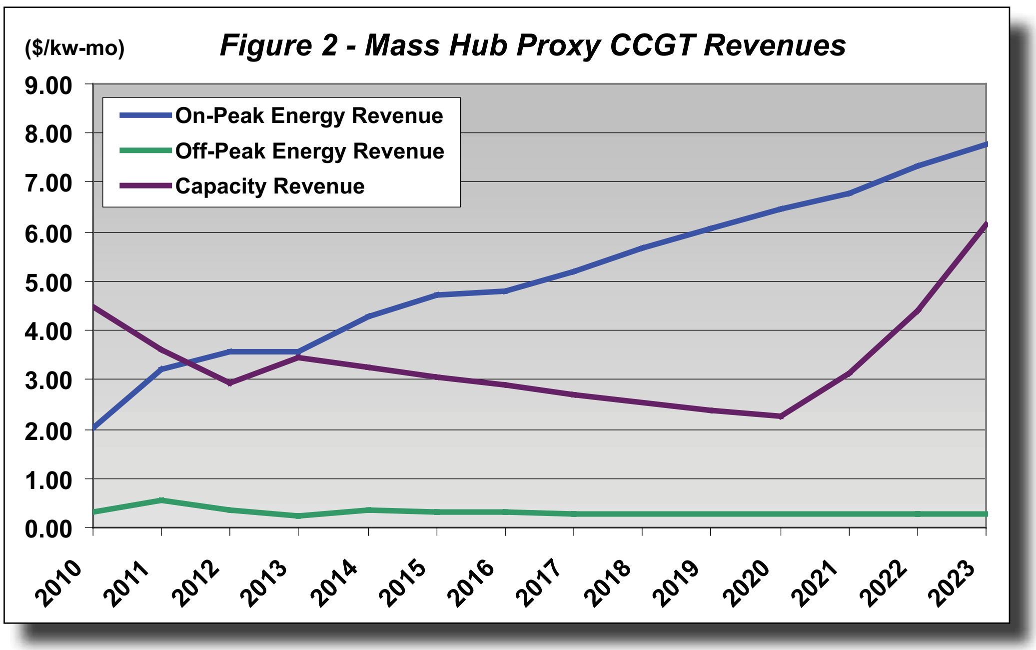


Figure 2 shows the trends for energy and capacity revenues expressed in $/kw-mo. Energy revenues in 2010 are expected to be near $2.00/kw-mo increasing to $5.00/kw-mo by 2017. Capacity revenues are forecast to be very low; declining from $4.50/kw-mo in 2010 to $2.25/kw-mo in 2020.

WHAT TO LOOK FOR:

- **LNG imports are expected to rise next year, and will rise even more in 2011 due to rapidly increasing supplies and higher North American prices.**
- **LNG imports should reduce long term upside price risk.**
- **Domestic production is not falling as fast as was expected earlier this year and aggregate supply for 2009 is exceeding the forecasts we made in March and June. The slower than expected rate of depletion from existing wells has lowered our forecast price for 2010 slightly.**
- **Demand from the industrial sector appears to have stabilized and may be ready to begin a slow and steady recovery. Under our current assumptions of a gradual economic recovery, however, industrial demand is just mildly bullish for prices in 2010.**

LNG TO KEEP PRICES IN CHECK AS DOMESTIC PRODUCTION EASES

Natural gas prices have been on a roller coaster ride for the past two years. Before that, prices had risen (circa 2002 to 2007) on steadily increasing demand from the power sector and domestic production that was struggling to keep pace. The long steady road to higher prices put a number of forces into play, some of them with medium-term consequences (1-2 years), and some with longer term consequences (1-4 years). Shorter-term effects are clear and can be measured by investment in domestic drilling (i.e. Baker Hughes rig counts), and the subsequent rise and fall in production levels. One of the medium term effects of the higher prices over the past five years has been increased investment in long-haul transcontinental pipelines. The Rockies Express (REX) is set to deliver 1.8 Bcf/day into the Consuming East in November. REX will provide increased take-away capacity to otherwise stranded production in the Rockies; will help to fill Consuming East storage facilities faster during the summers; and will stabilize (Henry Hub) basis pricing during the winter. Another medium-term effect has been increased investment and development of unconventional sources of gas (e.g. Barnett Shale, etc). Even further out on the effects horizon has been the increased investment and development in what is considered a virtually limitless supply of stranded gas that can be made available to North America and the rest of the world in the form of LNG. In this quarter's long-term outlook we re-examine the effects of LNG on the North American natural gas market.

LNG and the North American Supply Gap

Just a few years ago — before technological advances in unconventional gas recovery and the push for wind and renewable generation in North America – LNG was thought of as being unequivocally required to fill the growing gap between domestic supply and the growing demand from the power sector. ESAI, like the Department of Energy's Energy Information Agency (EIA) and most energy consultants, subscribed to this line of thinking. As late as 2006, the EIA was forecasting that annual LNG imports would account for between 4.4 Tcf and 10 Tcf by 2030 (or between 20 and 34 percent of annual natural gas consumption). The natural gas supply/demand gap, it was generally thought, would grow, prices would rise (creating incentives for LNG development), and North America would meet the growing demand for natural gas with imported LNG. Much has changed, however, over the past few years.

Since 2006, technological advancements in hydrofracking may have driven down the cost of production for unconventional natural gas while exploration for (and the discoveries of) unconventional gas reserves has grown rapidly. At the same time, the push for renewable energy and growing implementations of renewable portfolio standards has also begun to take center stage (decreasing expected dependence on natural gas to meet growing electrical demand). By the time the EIA published their 2008 Annual Energy Outlook (AEO), the estimate for LNG required to meet domestic natural gas demand in 2030 had fallen from 4.4 Tcf to 2.8 Tcf.

In the soon to be released 2009 AEO, a vastly different picture continues to emerge. Total net imports of LNG to the United States are significantly lower than in the AEO2008 reference case due to a re-evaluation of U.S. competitiveness for supplies on the world market. By 2030, the EIA now expects LNG imports of a mere 0.8 Tcf/year, is in line with LNG imports in 2007. The large gap in supply seen in 2006 is now expected to be met with domestic production. North American natural gas prices are expected to lag other demand centers and LNG cargoes will be drawn to other nations' import terminals with higher prices and inadequate domestic production. However, there is more to the LNG story.

As prices rose between 2004 and 2008, a great deal of LNG development began around the world. In 2006, global LNG production was around 8,200 Bcf (or the equivalent of about 37 percent of U.S. consumption). Project development began to increase rapidly based on the higher prices of the day and expectations of the growing gap in supply in the U.S. Project development began at a breakneck pace, and LNG production was expected to double over the next five years (to about 18,000 Bcf). An example of the level of commitment and investment required for an LNG liquefaction terminal is the Qatargas 2 project inaugurated earlier this year at an estimated cost of $13 billion. The annual LNG capacity from Qatargas 2 will be about 15.6 million tons (or about 725 Bcf/year). Using these rough figures the level of investment for all the new LNG projects contemplated is about $150 billion.